INTERN EXPERIENCE AT

SHELL WESTERN E&P, INC.

AN INTERNSHIP REPORT

by

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Submitted to the College of Engineering

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in partial fulfillment of the requirements for the degree of

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Major Subject: Petroleum Engineering

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ABSTRACT

Internship Experience at Shell Western E&P Inc.

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This report documents the author's internship experience with Shell Western E&P Inc., a subsidiary of Shell Oil Company, at Houston, Texas, during the period January 21, 1986 through January 21, 1987. It is intended to establish that this experience meets the objectives of the Doctor of Engineering internship.

Working as an engineer, the author has been involved in a variety of activities relating to engineering and business evaluations. These undertakings and the author's involvement have been described in this report. Major activities have included a waterflood enhancement study, infill drilling and primary well justifications, preparation of: development capital budget, reserves report, standardized measure of future net cash flows for the Securities and Exchange Commission 10k report, and an evaluation for the enlargement of an existing unit.

The author feels that he has benefited greatly from the internship experience and hopes that Shell Western E&P Inc. has benefited similarly.

DEDICATION

To the memory of my mother

Evelyn Mgbeke Obioha

ACKNOWLEDGEMENTS

Many people have been of assistance to the author, both during his academic pursuits and his professional internship. It is impossible to list everyone here; however, because of the importance of their contributions, the author wishes to express his thanks and appreciation to some very special people.

Many thanks to R. A. Startzman, who has so graciously drawn from his experience in academia and industry to counsel and guide me through my graduate petroleum engineering studies. Thanks also to the other committee members, Dr. P. B. Crawford, Dr. J. Lee, Dr. P. S. Rose, Dr. A. Garcia-Diaz, and Dr. R. R. Berg. My gratitude goes also to Dr. D. Von Gonten and Professor R. L. Whiting for their support and guidance during my graduate petroleum engineering studies.

Special thanks to Mr. Charlie Bremer, my internship supervisor. His support and interest throughout the internship have been unwavering. Mr. Bremer, in the author's opinion, is unsurpassed as an internship supervisor. Ann Dorlay, my direct supervisor, has made the months at Shell Western E&P Inc. the most intensive learning period the author has ever experienced. Her support throughout the internship is deeply appreciated. I am also very grateful to all the members of the Sun Acquisition Development Group, especially John T. Hansen and Vicki Kotila, for their cooperation and support during the internship. Additionally, the author is deeply grateful to the senior management of Shell Oil Company and the employees of Scallop Corporation for agreeing to the internship as well as arranging a suitable position.

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INTRODUCTION

1.1 INTERNSHIP OBJECTIVES

As partial fulfillment of the requirements for the Doctor of Engineering Degree at Texas A&M University, a professional internship with an industrial or governmental organization must be served. The purpose of the internship, as stated by the university, is twofold:

1. First, it should enable the student to apply his/her knowledge and training to the solution of a specific, practical, or relevant problem of particular interest to the organization with which he/she is working; and

2. Second, the internship should enable the student to become aware of the organizational approach to problems in addition to those of traditional design or analysis.

The purpose of this internship report is to certify that the above objectives have been met. The first objective was met with the intern completing the reservoir engineering requirements for the following projects:

The citations on the following pages follow the style of the *Journal of Petroleum Technology*

- A waterflood enhancement study;

- A justification for infill drilling and producer-to-injector conversions; and

- A justification to drill an Abo reef primary well.

The second objective was met with the intern interacting on a daily basis with engineers from different disciplines, and sometimes with members of management. These interactions provided the intern numerous opportunities to observe and understand the company's approach towards field development and management. The author also completed several business related assignments, which include:

- The preparation of the 1987 Development Capital Budget;

- The preparation of the 1987 Reserves Report;

- The Standardized Measure (Government Reporting) exercise; and

- A Unit Enlargement Evaluation (analysis for the expansion of an existing unit).

1.2 THE INTERNSHIP ORGANIZATION

With the title of Engineer, the author has served his internship at the Houston, Texas office of Shell Western E&P Inc., within the Western Production Division. Shell Western E&P Inc. is a subsidiary of Shell Oil Company. The latter is one of the several operating companies of the Royal Dutch/Shell Group (Figure 1-I).

Royal Dutch/Shell Group

The Royal Dutch/Shell Group (generally known as Shell after its seashell trademark) is the product of an alliance made in Indonesia in 1907 between the Royal Dutch Petroleum Company of the Netherlands and the Shell Trading and Transport Company Limited, a British company.[1]

Shell companies together now form the second largest business enterprise in the world.[2] They handle about a tenth of the World's oil and natural gas outside centrally planned economies, exploring for and producing, purchasing, processing and selling them. They form the eighth largest chemical business in the world, which represents the largest total investment in chemicals by any of the major oil companies. Shell companies also produce and trade in coal and non-ferrous metals.

The organizational structure of Shell is very unusual but interesting. The usual pyramidal organization composed of layers of vice-presidents of varying degree heading the operating divisions and culminating with a chief executive and board of directors who meet monthly is absent.[3] In its place are two parent companies, the Royal Dutch Petroleum Company and the "Shell" Trading and Transport Company, Limited, each with its own board of directors. Each of the two companies is responsible to its own shareholders. Shares of one or both companies are listed and traded on stock exchanges in eight European countries and in the USA.[4]

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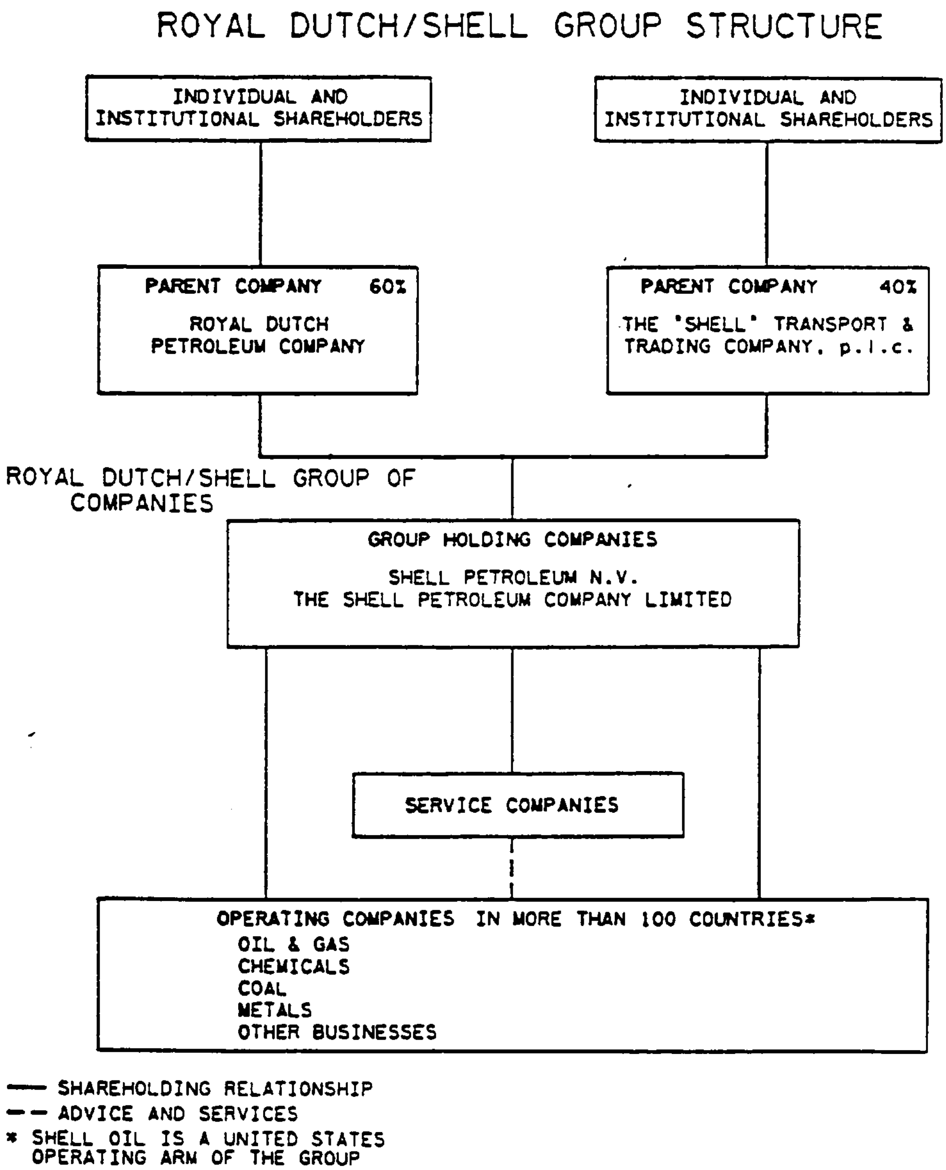

Figure 1-I

The Dutch and British parents hold interest on 60:40 basis in the Group which, in outline, consists of:

- Group holding companies, namely Shell Petroleum NV and the Shell Petroleum Company Limited (see Figure 1-I), to the boards of which the parent companies appoint directors and from which they receive income in the form of dividends. These two holding companies in their turn own between them, directly or indirectly, shares in all other Group and associated companies;

- Operating companies, of which there are several hundred around the world, engaged in various branches of oil and natural gas, chemicals, coal, metals and other businesses. They are not all wholly owned. Many are joint ventures with other companies or governments; and

- Service companies, variously located in the Netherlands or the United Kingdom, where main business is to provide specialized advice and services to other Group and associated companies.

Top management of the Group is composed (in 1985) of eight Managing Directors and below them a number of geographical and functional coordinators.[4] The Group Managing Directors are also directors of the service companies, by which they are appointed to the Committee of Managing Directors, which considers, develops and decides upon overall objectives and long-term plans to be recommended to operating companies.

The management of each operating company is responsible for the performance and the long-term viability of its own operations. But, the operating companies are all expected to conform to certain standards which are upheld throughout the Group; these include accounting practices, safety standards and protection of the environment. This authority structure could be described as decentralized management which seems to be on a country basis with more emphasis on local management. The operating companies are coordinated by the central offices (in London and The Hague), not managed, at least not directly. The tools of coordination are personnel assignments, planning, and internal competition.[3]

Shell Oil Company

Shell Oil Company (Shell Oil) is one of the fully owned operating companies of the Group. It is a fully integrated oil and gas company whose activities are concentrated mainly in the United States. In other words, it is involved in both upstream (exploration and production) and downstream activities (refining and marketing). The latter are handled by the "Products" arm of the corporation, while the former are carried out through an investment holding company structure with focused operating subsidiaries (Figure 1-II). The research and development functions of Shell Oil are conducted by Shell Development Company. Shell Oil has its own Board of Directors made of two senior Managing Directors of the Group, the Chief Executive and President of Shell Oil, the Executive VP of Exploration and Production, the Executive VP of Products and some outside members. For purposes of relevance,

SHELL OIL CORPORATE STRUCTURE

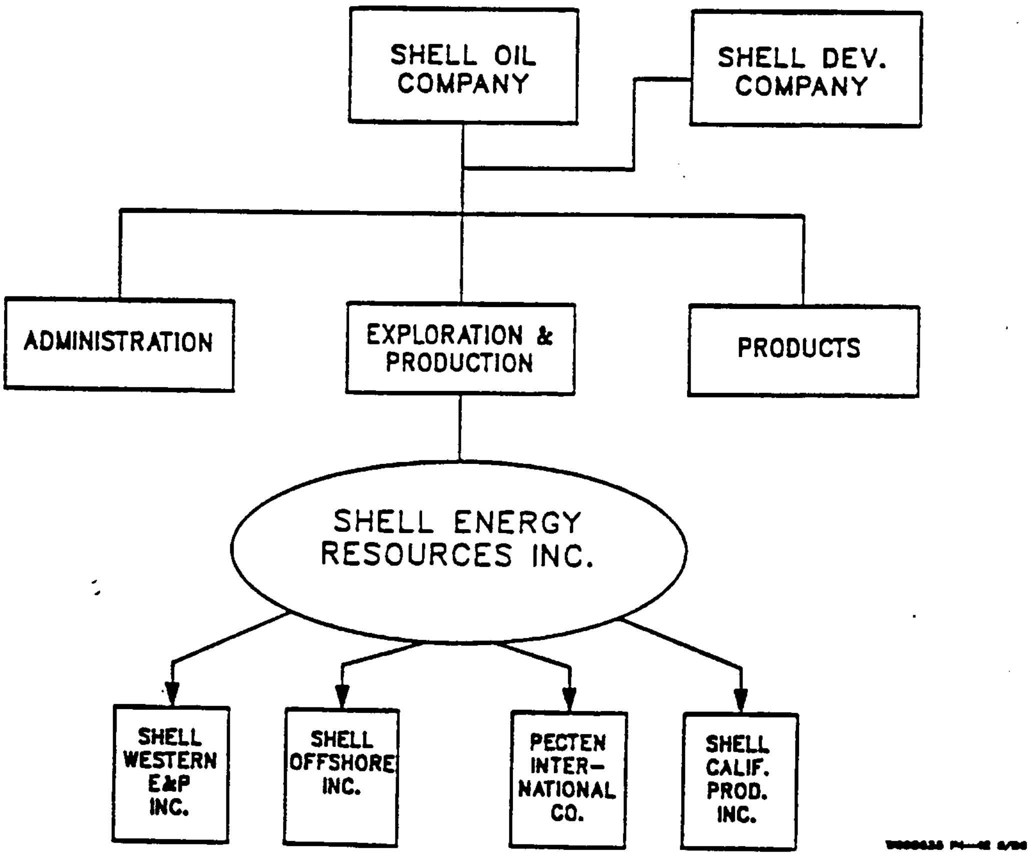

Figure 1-II

further discussions will be limited to the organizational aspects of the exploration and production functions.

As mentioned above, Shell Oil's exploration and production functions are organized into a holding company structure (see Figure 1-II). Shell Energy Resources Inc. (SERI) serves as a holding company for Shell Western E&P Inc., Shell Offshore Inc., Pecten International Company, Shell California Production Inc., and Shell Mining Company.

SERI is incorporated in the state of Delaware. Its Board of Directors is composed of some of the top executives of Shell Oil. The President of Shell Oil is the chairman of SERI; other directors include the Executive VP of Exploration and Production, and the VPs for Exploration and Production.

Each subsidiary has its own Board of Directors, made of the subsidiary President, the Executive VP of Exploration and Production (E&P), and the VPs of Exploration and Production for Shell Oil. The subsidiary Boards provide a corporate wide perspective for overview and stewardship of the E&P functions. Management resides in the officers of the subsidiaries under the direction of their Boards of Directors.

The parent-subsidiary relationships of Shell Oil and the E&P entities are handled by "Service Agreements". These agreements are contracts which provide that a particular subsidiary and Shell Oil will make personnel available to provide advice and consultation to the other on areas in which one has a special expertise or where one will provide certain functions for which the other does not have staff. These services are provided as an independent contractor, that is, much like an outside consulting firm. One company is compensated by the other for services rendered. These services include: Budget Reviews, Auditing, Staff Planning, Technical Consultations, Research Assistance, Project Planning, Information Processing etc.

Having defined the relationship between Shell Oil and its E&P subsidiaries, the following discussions would focus on the organizational description of Shell Western E&P Inc., the subsidiary home of the author's internship.

Shell Western E&P Inc.

Shell Western E&P Inc. (SWEPI) has four divisions: (1) Eastern, (2) Central, (3) Western, and (4) Alaska. Figure 1-III shows the various divisions and the areas of United States they cover. Shell Western's top management includes a President, a General Manager for Exploration, and a General Manager for Production. Each division is headed by two managers, a Production Manager and an Exploration Manager. The former reports to the General Manager for Production, and the latter to the General Manager for Exploration. The author was an intern in the Western Production Division, and the organizational chart for the Western Production Division is shown in Figure 1-IV. For purposes of relevance, organizational description will be limited to this division.

Western Production Division

The Western Production Division is responsible for the development and management of fields under the charge of the Western Division. These responsibilities include:

SWEPI PRODUCTION DIVISIONS

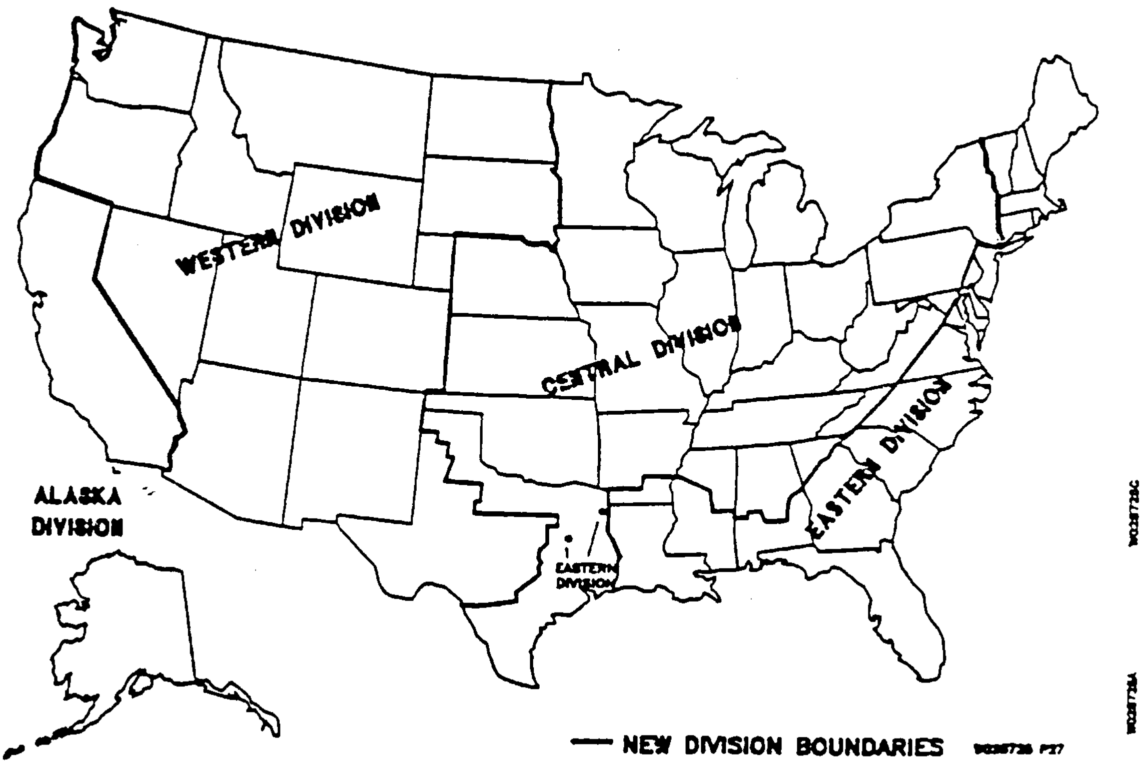

Figure 1-III

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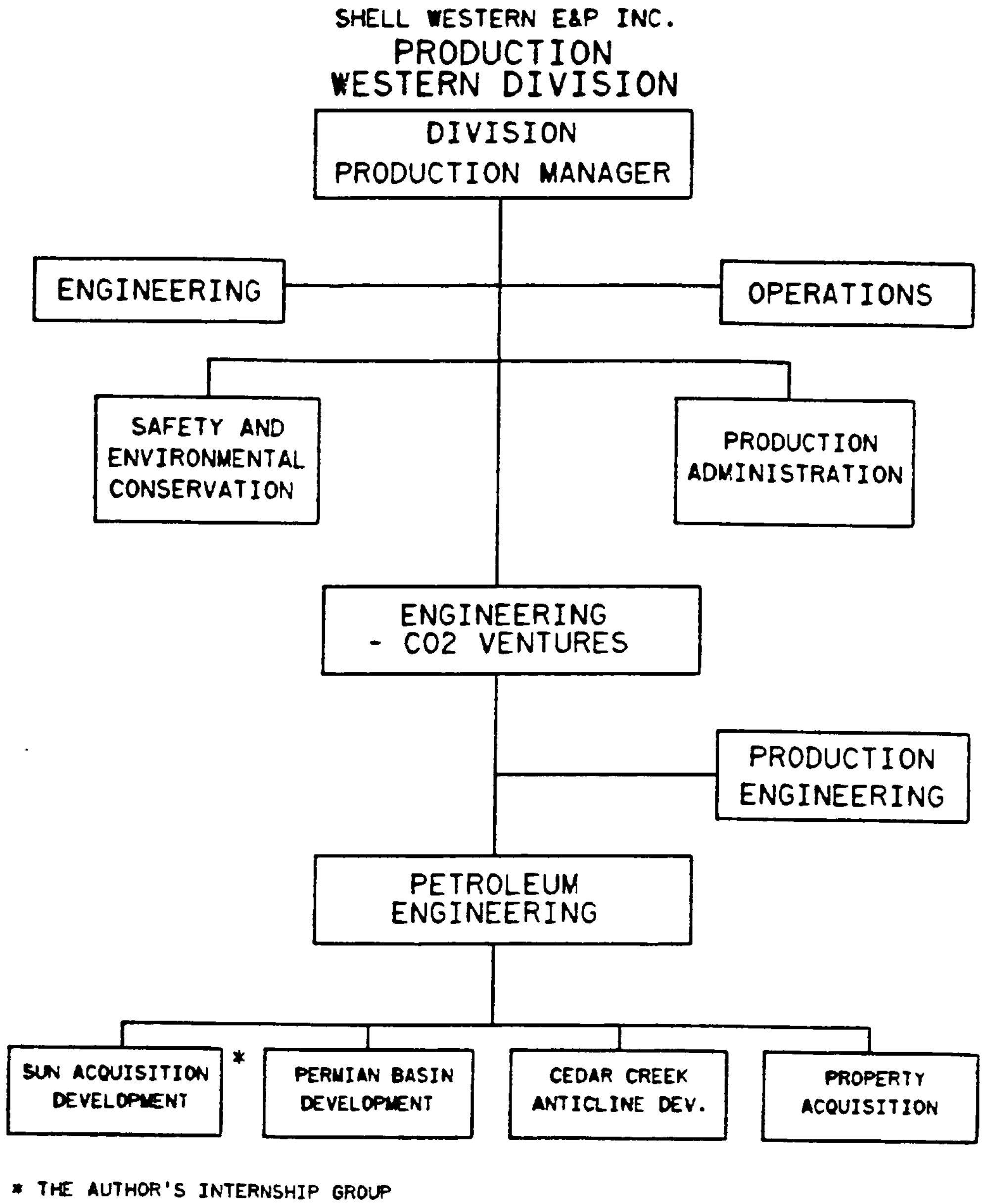

Figure 1-IV

- Field Development
  - Delineation and Development of new fields through development drilling;
  - Development of supplementary recovery projects (waterflooding, CO_2 flooding, etc); and
  - Enhancement of existing supplementary recovery projects through infill drilling and implementation of injection improvements.

- Reservoir Management
  - Development of operational reservoir management strategy that provides options for reservoir operations and controls;
  - Investigating the operational techniques that are used to exploit a reservoir and to carry out studies to improve the techniques or to devise new ones;
  - Studying any changes in operational procedures that may be required to take full advantage of reservoir processes or to enhance reservoir measurements; and
  - Surveillance of supplementary recovery projects.

The Division had a staff level of about 800 employees as of December 31, 1986. This included managers, engineers, designers, administrative employees and support staff.

Organizationally, the Division has six functional units: Engineering, Engineering-CO_2 Ventures, Operations, Safety and

Environmental Conservation, Production Administration and Land. Each of these units participates in carrying out work in some phases of the activities described above. A description of their activities will follow.

Engineering, has responsibilities for the engineering development of some fields as well as for providing services for the entire Division. These services include field facilities design, facilities cost estimating, drilling program design, drilling cost estimating, and well evaluation training for new engineers. This unit is headed by an Engineering Manager.

Engineering-CO_2 Ventures, can be classified as having two departments: Development (Petroleum Engineering) and Support. The Petroleum Engineering Department, headed by Mr. Charlie Bremer (the author's internship supervisor), is composed of four groups whose activities are strictly developmental, except for the Property Acquisition Group. The Sun Acquisition Development (the author's internship group), Permian Basin Development, and Cedar Creek Anticline Development are responsible for the technical planning and economic justification of major development projects for some fields located in West Texas (including the famous Wasson Denver Unit) and the Cedar Creek Anticline in Montana. Each of the groups is made of reservoir engineers, geological engineers, and petrophysical engineers. The Property Acquisition Group, as the name implies, is responsible for identifying acquisition opportunities for the Division; it is made up of very experienced reservoir engineers.

The Production Engineering arm of the Engineering-CO_2 Ventures is responsible for providing production engineering and waterflood surveillance services for the fields that have been developed, or are in process of development by the three Development Groups mentioned earlier.

The Engineering-CO_2 Ventures is headed by an Engineering Manager.

Operations, is responsible for providing field support necessary to oversee producing functions. This unit is also responsible for providing short-term targets of oil and gas production volumes for the division, as well as ensuring that the projected targets are met.

The Operations unit is headed by an Operations Manager.

Safety and Environmental Conservation, is responsible for monitoring field operations for compliance with safety and environmental regulation guidelines of the company and governmental authorities. They solicit for state permits when harzardous waste may be produced during field operations. Additionally, this unit has the responsibility of reviewing field facilities design to ensure compliance with safety regulations. This unit is headed by a manager.

Production Administration, has the responsibility for coordinating the Business Cycle Activities (Capital Budgeting, Standardized Measure for Government Reporting, Reserves Report Preparation) of the Division with Shell Oil. It also acts as a coordinator between the Division and outside companies in joint-venture matters. Additionally, Production Administration interfaces with regulatory authorities on matters pertaining to drilling permits, fluid injection permits etc.

This arm of the Division is headed by a Production Administration Manager.

CHAPTER 2

ORGANIZATIONAL APPROACH TO FIELD DEVELOPMENT PLANNING

One of the major objectives of the Doctor of Engineering internship is for the intern to become acquainted with the employer's approach to problems, which are non-technical in nature. In the course of the internship, the author had opportunities to observe Shell's approach towards field development planning, and this subject will be discussed in this chapter.

In the oil business, field development is used to describe a host of activities ranging from development drilling to the installation of supplemental recovery projects. The approach used in the implementation planning of any of these activities is nevertheless similar. Therefore, the following discussion on the planning phase of a development drilling project can be considered as an overview of general project development approach in the entire Company.

The desired outcome of any project development effort is the completion of a task or attainment of specific objectives. In the case of development drilling, the desired product is the completion of an oil producing well. The planning of a drilling project requires a coordinated effort of several groups. The coordinating group is the Engineering Development. Descriptions of these groups and their contributions during project planning will follow.

Engineering Development

Engineering Development is the focal point of all the planning activities (Figure 2-I). This group is made up of reservoir engineer(s), geological engineer(s), and petrophysicists(s). One specialty engineer is usually assigned to a project; an exception would require a very large project with unusual time constraints. The responsibilities of this group are:

- Project Definition
  - Specifying the number of wells to be drilled
  - Picking the locations of the wells
  - Specifying the target depths
  - Specifying time targets
  - Specifying well evaluation tests

- Project Justification
  - Conducting technical evaluations
  - Conducting profitability assessment
  - Soliciting management approval via presentations

- Project Coordination
  - Requesting for information and receiving input from other groups
  - Initiating action for drilling permits application
  - Initiating action for well location staking

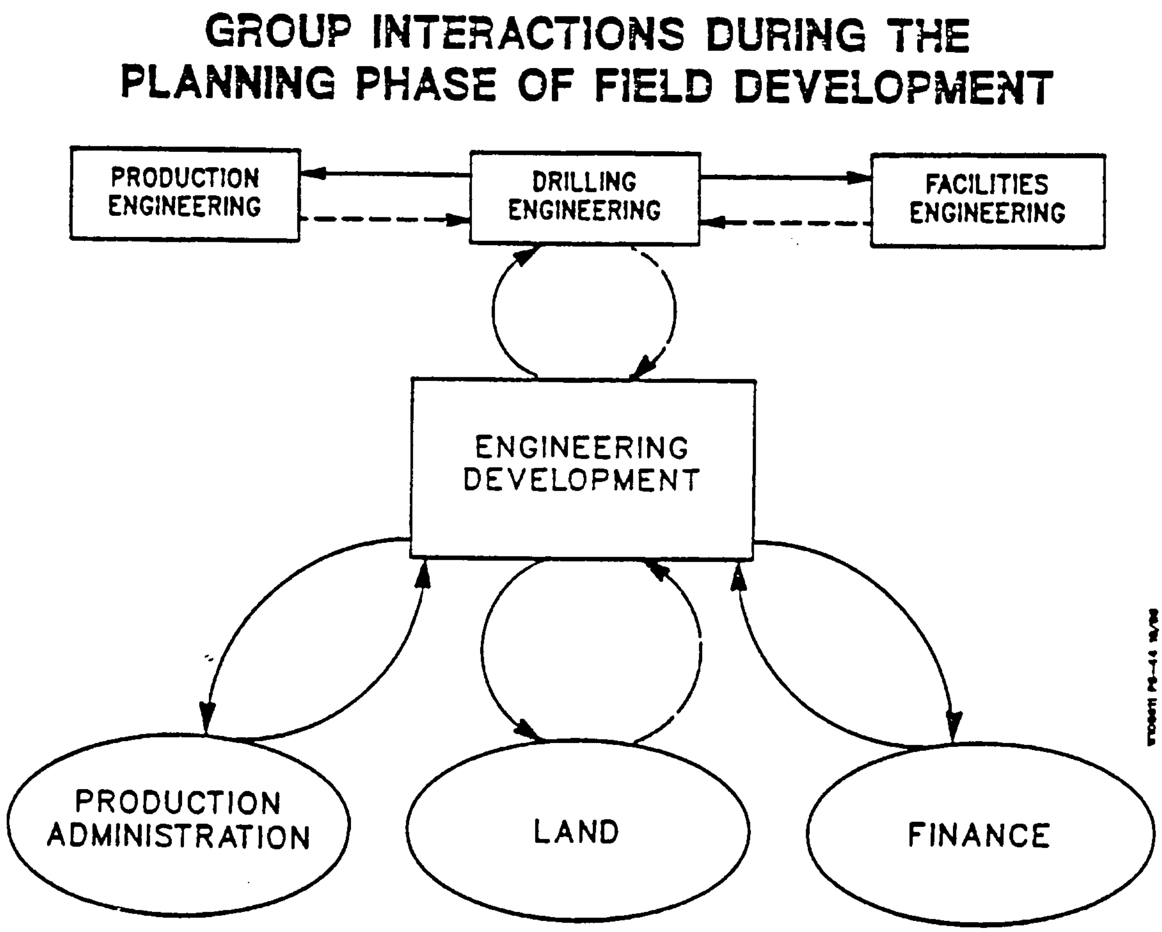
GROUP INTERACTIONS DURING THE PLANNING PHASE OF FIELD DEVELOPMENT
PRODUCTION ENGINEERING
DRILLING ENGINEERING
FACILITIES ENGINEERING
ENGINEERING DEVELOPMENT
PRODUCTION ADMINISTRATION
LAND
FINANCE

Figure 2-I

- Sending the Authority for Expenditure (AFE) to Finance
- Communicating status of project to other groups and members of management

Drilling Engineering

The Drilling Engineering group is indispensable in the planning of drilling projects. Membership includes drilling engineers, and field drilling foremen. The primary responsibility of this group is to ensure that drilling operations are conducted timely, economically and safely. Specific planning responsibilities include:

- Drilling Prognosis
  - Analyzing subsurface pressure data to identify possible zones of pressure anomaly (over-or-underpressure)
  - Specifying drilling fluid types and densities for specific depths
  - Specifying casing points, size and nominal weight

- Cost Estimation for
  - Rig mobilization
  - Total footage/and or rig days
  - Casing, Drill pipe, etc.

- Coordination
  - Interfacing with Facilities and Production Engineering

- Summarizing cost estimates from Production and Facilities Engineering, and providing a summary to Engineering Development.
- Short-listing of drilling contractors
- Material requisitions
- Scheduling of drilling

Production Engineering

This group is made up strictly of production engineers. Their responsibility ranges from downhole engineering to the installation of X-mas trees (surface production control equipment). Specific contributions in project planning include:

- Production Tubing design
- Artificial Lift design
- Well Completion design
- Cost Estimation for tubing, completion and production testing

Facilities Engineering

The Facilities Engineering group is responsible for the transportation of produced hydrocarbons from the wellhead to the LACT unit (measuring station for crude oil entering market pipeline). Specific contributions in planning include:

- Flowline design
- Separator design
- Review of well tolerance limits
- Cost estimation for necessary facilities and pipes

Production Administration

Production Administration is actually a multi-functional administrative department as opposed to a group. However, it has a group (Regulatory and Permits) whose responsibilities pertain to filing of drilling permits, etc.

Land

The Land Department has personnel whose contributions to project planning include designating the actual well locations in the field, and applying for title clearance.

Finance

The role of the Finance group in the planning process is to certify that the total expenditure in the project AFE is within the approval authority of the signatories. Additionally, in a joint-venture project, Finance has to ascertain that the project has received the minimum required vote of partners.

CHAPTER 3

TECHNICAL ASSIGNMENTS

3.1 INTRODUCTION

During the internship, the author had responsibilities for a Shell-operated Unit in West Texas. This Unit will be referred to hereinafter as the Permian Basin Unit, due to proprietary reasons. One of the responsibilities involved the completion of a waterflood enhancement study. Other technical responsibilities involved the completion of justifications for two development projects. The first justification was for infill drilling and producer-to-injector conversions, and the second was for the primary development of a field producing from a reef.

3.2 WATERFLOOD ENHANCEMENT STUDY

The Permian Basin Unit (PBU) was formed in February, 1980, and operated by Sun Oil Company till January, 1986, when unit operations were transferred to SWEPI. Following the transfer of operations, a field study was initiated in order to evolve an operating plan that would optimize the recovery of existing flood. To accomplish the goals of the study, an integrated geological, petrophysical and reservoir engineering approach was adopted. Significant contributions were made by a geological engineer (John Hansen) and a petrophysical engineer (Vicki Kotila) during the course of the study. In order to conform to the purposes of the report, only the reservoir engineering aspects of the study will be presented to illustrate the intern's contributions.

Location and Geology

Geologically, the PBU is located near the southeastern margin of the Northwestern Shelf, a feature of the Greater Permian Basin. The unitized interval consists of the Middle Clearfork, Tubb, Lower Clearfork and Wichita-Albany formation (Figure 3-I) with a gross thickness of approximately 1900 feet. Depositional environment ranges from shelf margin facies in the Lower Clearfork/Wichita to slightly backshelf in the Middle Clearfork. A limited amount of "reef" facies is also present in the Wichita (Figure 3-II). The reservoirs were deposited in a shallow marine environment and consist of dolomite with varying amounts of anhydrite and terrigenous silt. Individual pay beds are thin (average <5 feet) and limited in areal extent.

Producing Characteristics and Physical Properties

The primary oil production performance was indicative of a solution gas drive mechanism. There has been no evidence of a gas cap or active water drive. Physical properties of the reservoir are shown in Table 3-I. This field is representative of many other Permian fields with generally low porosity and permeability. Low permeability is compensated partially by low-viscosity reservoir crude oil. The 1.2 cp viscosity is typical of many West Texas Permian fields.

Field Development

The PBU field was discovered in 1954. This was followed by seven years of slow development and substantial increase from 1962 to 1970. Development thereafter was sporadic through early 1980, the period

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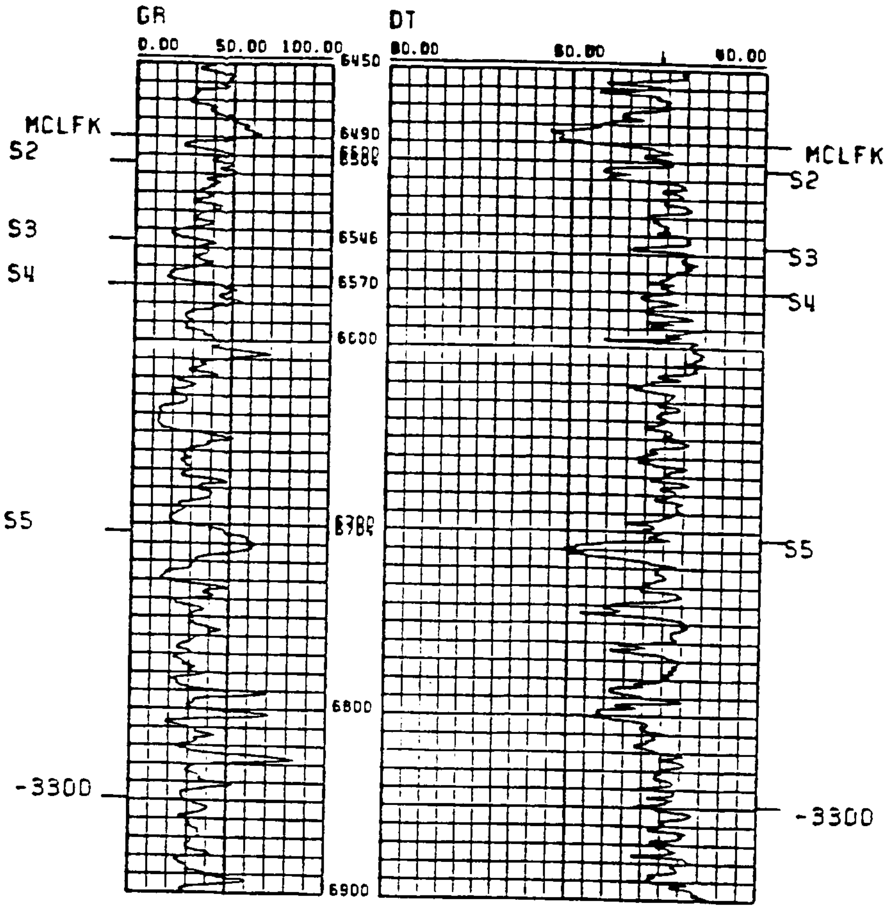

Figure 3-I

PERMIAN BASIN UNIT

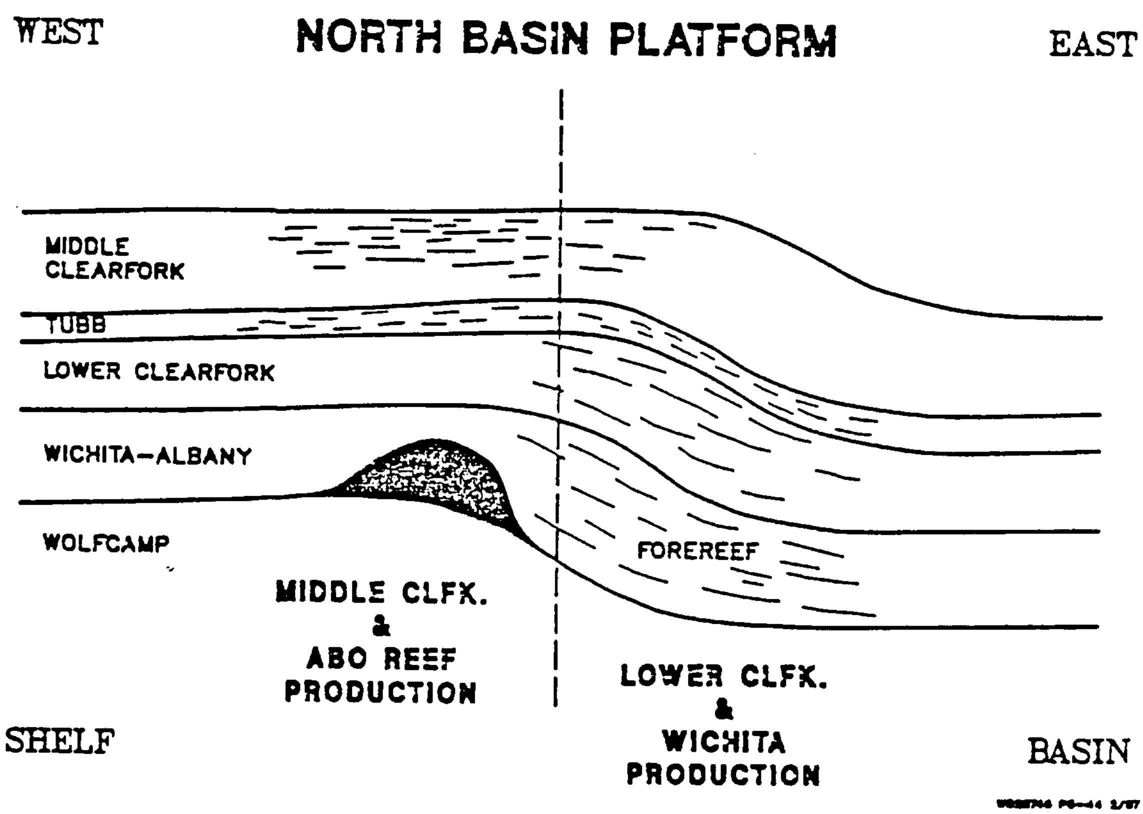

Figure 3-II

TABLE 3-I

AVERAGE RESERVOIR PROPERTIES

Reservoir	
Area, acres	4300
Depth, ft	6400-8200'
Net pay, ft	145
Porosity, %	6
Permeability, md	.5
Connate water, %	30
Initial Pressure, psig	2643
Fluid	
Stock-tank gravity, °API	28.1
Oil Viscosity, cp	1.2
Formation volume factor, Rbl/STB	1.3

of unitization. The bulk of primary development was on 40-acre well spacing. Waterflood operations were initiated in March, 1983. The flood was developed on 160-acre inverted 9-spot pattern (Figure 3-III) with plans for modification to a line drive pattern. Table 3-II shows the field operating data.

Study Objectives

Within the framework of enhancing the waterflood performance and evolving a plan for future development, the main objectives of the study were defined as follows:

1. To determine the effective original oil in place;

2. To determine the effectiveness of the current flood and potential for improvement under existing operations; and

3. To determine the potential for infill drilling and alternate operating plan.

Original Oil in Place

The lack of pressure and reliable production data for PBU precluded the use of material balance technique in calculating the original oil-in-place (OOIP). This left the volumetric approach as the only option. Two major problems were encountered in generating the necessary geological and petrophysical data needed for volumetrics. First, only two cores were available for the entire field. This raised

PERMIAN BASIN UNIT
EXISTING PATTERNS

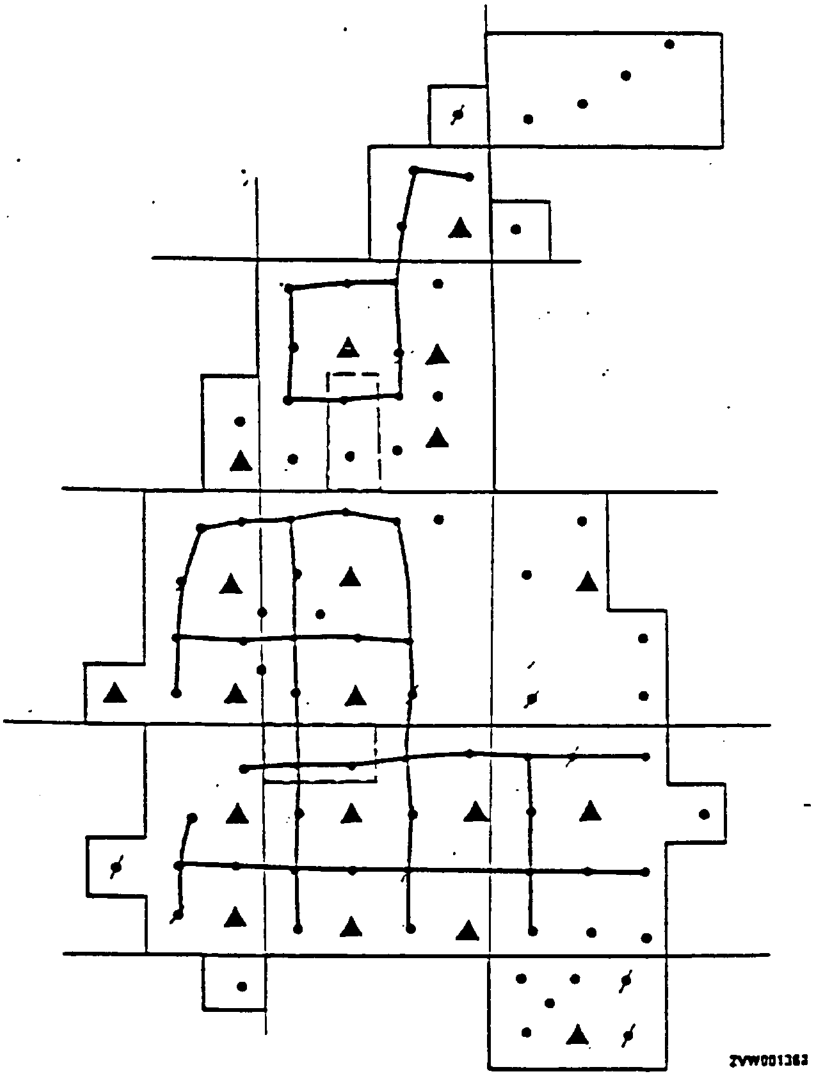

Figure 3-III

TABLE 3-II

FIELD OPERATING DATA

Unitization	February 1980
Water Injection (started)	March 1983
Productive Zones	Middle and Lower
	Clearfork Wichita Abo Reef
Well Spacing	40 Ac.
Pattern	Incomplete inverted 9-Spot
Well Count	
Oil	60
Injectors	20
Temp. Abandoned	18
Production/Injection Data (1/87)	
Oil	1189 B/D
Water Cut	70%
GOR	320 SCF/B

questions regarding reservoir representativeness of the cores. Core data are very useful in calibrating well logs when sufficient samples are available. Second, most of the available well logs are either of the sonic or the neutron type. Both logs have to be available for the same well in order to determine lithology accurately. Consequently, it was difficult to determine what was "pay". These problems meant that the volumetric OOIP could be very unreliable due to significant uncertainties in input data -- pay thickness, porosity, and productive area. In order to circumvent this problem, the intern used the Monte Carlo simulation technique for the volumetric calculations. Monte Carlo simulation treats solutions with continuing cognizance of the limiting ranges of accuracy and reliability.

The Monte Carlo simulation technique consists of mathematically simulating an experiment for an expression involving one or more parameters, each of which has its associated uncertainty. The experiment uses a random sampling of the input parameter distributions involved in the expression being studied. A single run is synonymous with an experiment, and the output constitutes an observation. If a sufficiently large number of observations are averaged, the integrated outcome represents the expected solution which will be obtained in the long run.

For instance, in order to determine the OOIP, the following could be treated as independent random variables: porosity, area, formation thickness, water saturation and formation volume factor. A value of each independent random variable is selected from its respective probability distribution. This set of values is then substituted into the expression,

$$N = \frac{7758(\phi)(A)(h)(1-Sw)}{Bo} \quad \text{------------------------} \quad (1)$$

Where 7758 = number of barrels per acre-foot,

ϕ = porosity, fraction

A = area, acres

h = thickness, feet

Sw = water saturation, fraction

Bo = formation volume factor, RBb/STB

N = reservoir oil initially in place, STB

A value of the dependent variable, N, is calculated. Subsequent values are obtained by repeating the simulation process with additional sets of randomly samples values of the five independent variables. The simulation process continues until the expected values of N converges around a particular number.

In determining the OOIP in PBU area, a modified form of equation 1 was used:

$$N = PV * \frac{(1-Sw)}{Bo} \quad \text{------------------------} \quad (2)$$

Where PV = reservoir pore volume, Rbbls (7758Ahϕ)

Reservoir pore volume was determined by the geologist using porosity-foot contour maps, and was considered an independent variable.

The uniform distribution was selected for pore volume, while the triangular distribution was chosen for the water saturation and initial formation volume factor. These distributions are believed to reasonably approximate the variables (Figure 3-IV). Input parameters for the simulation are provided in Table 3-III.

Figure 3-V shows the calculated cumulative probability distribution of OOIP. To the degree that the input factors are realistic, the expected OOIP was calculated to be 118 million. This value was based on 1000 simulation runs, but the mean convergence test indicated that stability was reached in less than 200 iterations. In other words, the cumulative average of the OOIP values converged to the expected value in less than 200 simulations. As shown in the figure, the probability associated with the predicted mean value is 49%. There is a 90% possibility that the minimum OOIP is 94 million STB and a 10% probability that the maximum is 144 million STB. The simulation runs were conducted using the Monte Carlo option in the Interactive Financial Planning System (IFPS) software owned by Shell. Note that IFPS is a trademark.

Flood Performance Review

One of the initial activities completed during the field study was a detailed review of the waterflood performance. This was necessary in order to determine the effectiveness of the current flood operations and the potential for improvement under existing operations.

Figure 3-VI shows the plots of the actual oil production and the forecast of the Technical Sub-Committee for Unitization. The plots indicate that the flood response has been less than predicted. Hence, a

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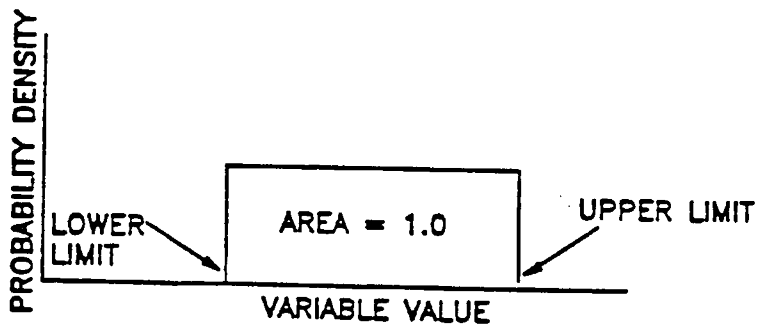

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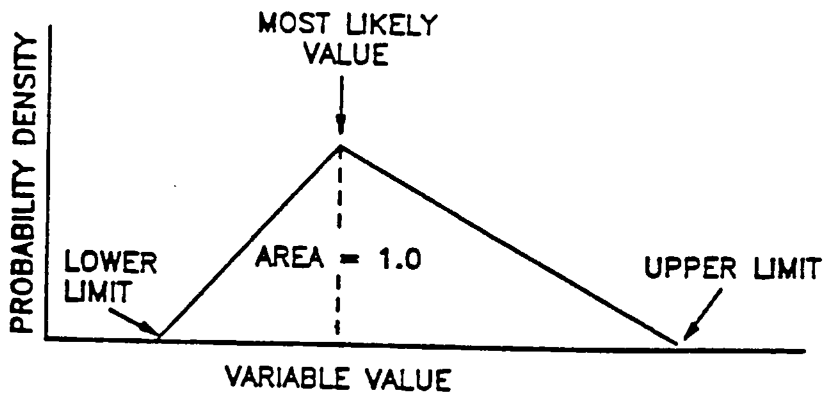


Figure 3-IV

TABLE 3-III

MONTE CARLO ANALYSIS
INPUT PARAMETER DATA
FOR
THE PERMIAN BASIN

DISTRIBUTION PARAMETER	PROBABLE MINIMUM	MOST LIKELY	PROBABLE UPPER LIMIT	TYPE
Pore Vol (MMRBLS)	155.9	-	259	Uniform
S_w(%)	23	30	37	Triangular
BOI	1.1	1.25	1.3	Triangular
Infill Rec. Fac (as % of OOIP)	4	6	8	Triangular

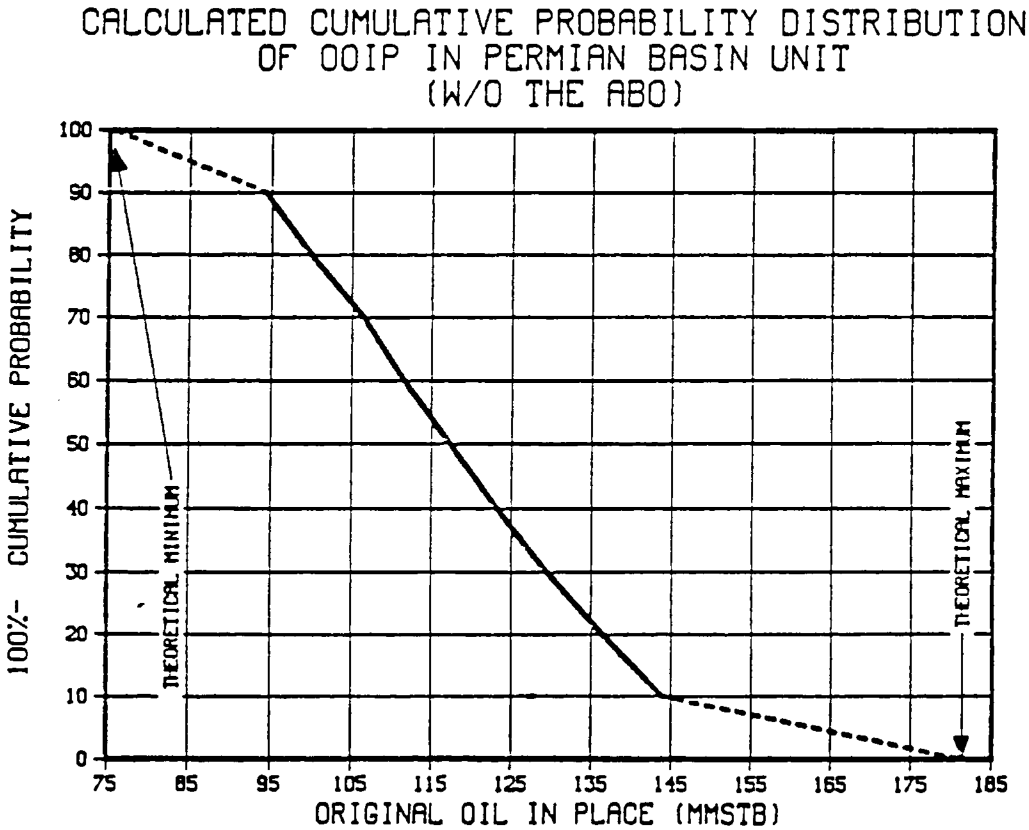

CALCULATED CUMULATIVE PROBABILITY DISTRIBUTION
OF OOIP IN PERMIAN BASIN UNIT
(W/O THE ABO)
100%- CUMULATIVE PROBABILITY
0
10
20
30
40
50
60
70
80
90
100
THEORETICAL MINIMUM
THEORETICAL MAXIMUM
75
85
95
105
115
125
135
145
155
165
175
185
ORIGINAL OIL IN PLACE (MMSTB)

Figure 3-V

PERMIAN BASIN UNIT OIL PRODUCTION PLOT

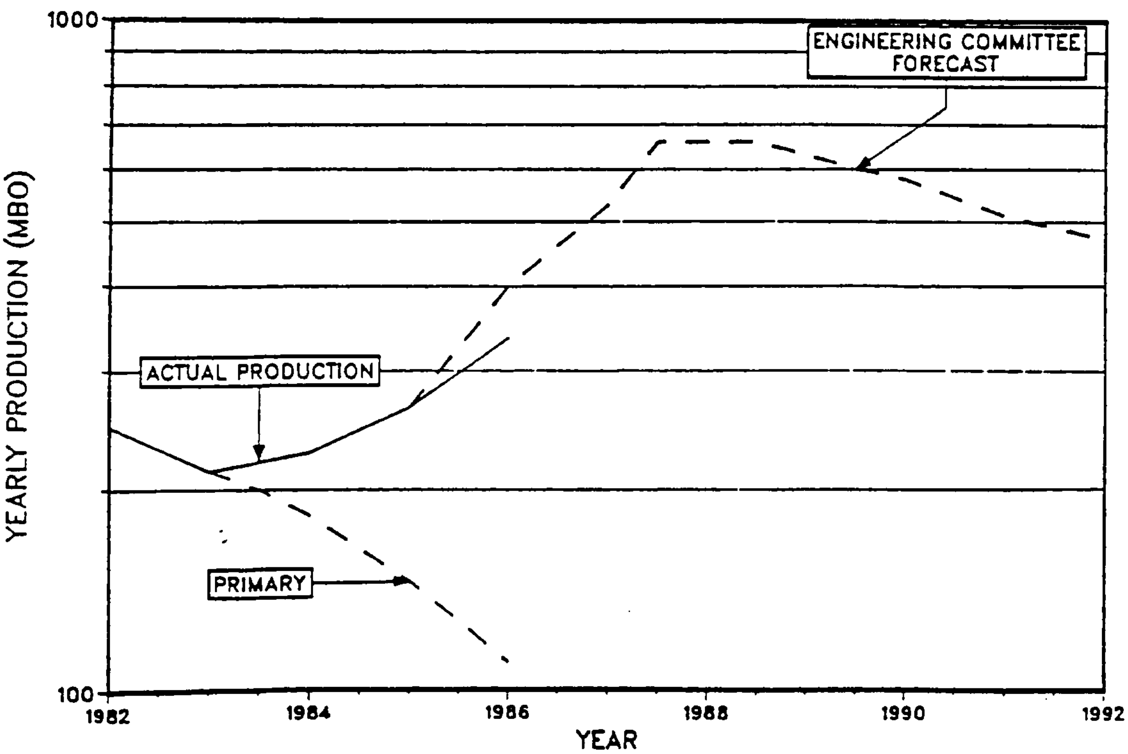


Figure 3-VI

review process was begun to identify the reasons for the observed performance and propose remedies.

The review was conducted on a well-by-well basis, and by patterns. A Field Monitoring Program (FMP) in the Petroleum Engineering CO_2-Ventures was used by the intern to access the production data and generate individual well curves. Based on the analysis of the production data for all the unit wells, it was apparent that only a few producers had responded to the flood. Further investigations included: (1) the preparation of producer-to-injector cross-sections by the geologist to determine if the corresponding pay intervals are open in both the producers and injectors; and (2) a detailed comparison of fluid injection and withdrawal volumes in each pattern by the intern. The results of these investigations are as follows:

1. Corresponding pay intervals between the injectors and many producing wells were found to be unopen. A basic prerequisite to successful waterflood operation is that corresponding pay intervals be effectively completed in both producers and injectors.

2. The injection operations was found to be ineffective. There was overinjection in many patterns and areas, while the voidage requirements in other areas were not being met.

The above observations indicated that improvements in the waterflood performance could be effected through redistribution of injection, addition of more injectors, and opening up of more pay in both producers and injectors. The intern recommended that these measures be implemented in order to improve the waterflood oil recovery.

Infill Potential

One of the most interesting developments in the exploitation of West Texas carbonate reservoirs is the use of infill drilling to optimize recovery during waterflood operations. This benefit is a direct result of better understanding of carbonate reservoirs.

Major portions of carbonate reservoirs have been found to consist of numerous (±50) thin (1.0-10 feet) stringers that may or may not extend to offset wells (Figure 3-VII). Although this lack of continuity is generally not a serious problem during the primary phase of production, it can severely limit waterflood effectiveness. In addition, many of these reservoirs have directional permeability and/or an existing or induced fracture system which can result in poor waterflood sweep efficiencies.

Shell and other Permian Basin operators[6,7,8] have observed that one of the most effective means of overcoming this continuity problem is to drill wells on closer spacing. Where directional fluid movement is found to be a problem, the infill drilling is usually accompanied by a change of the injection pattern. Some of the factors identified as contributing to the success of infill drilling are:

CONTINUITY CONCEPT

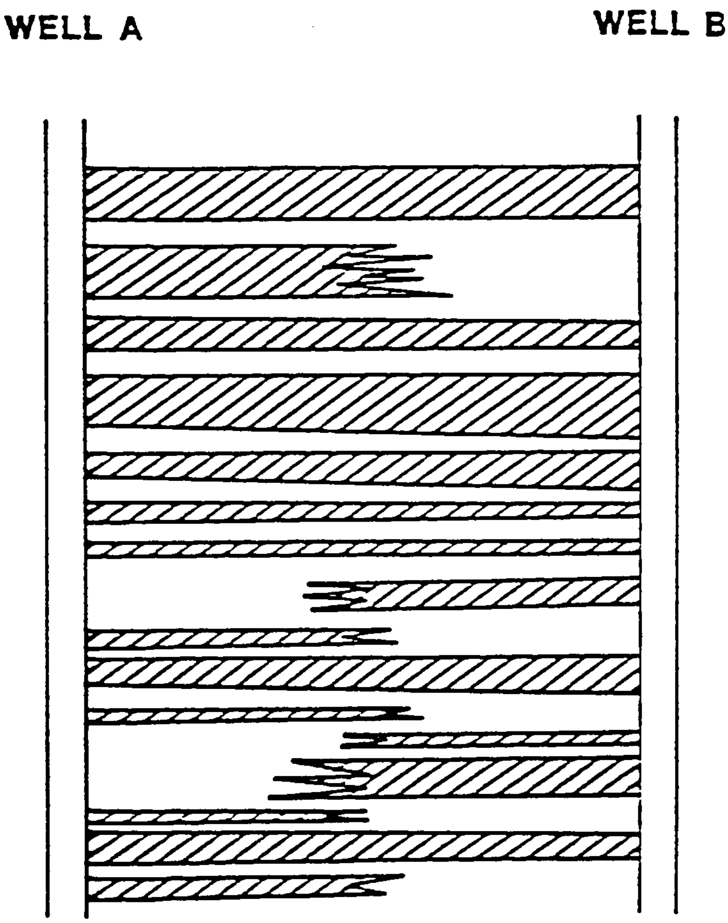


Figure 3-VII

1. Improved area sweep

2. Improved vertical sweep

3. Improved lateral continuity

Each of the above factors effects recovery improvements, and the magnitude of improvement for a particular field would be a function of reservoir quality (permeability, gross to net reservoir thickness, etc.), and operating flood pattern. Recovery improvements have generally been quantified as percentages of OOIP. For instance, both Amoco[7] and Exxon[8] have reported improved recoveries ranging from 2.0 to 8.0 percent of OOIP by infill drilling from 40 to 20 acres/well in existing waterflood.

The intern estimated the 20 acre infill recovery potential in PBU using the statistical volumetric method and analogy. The statistical volumetric method is based on the Monte Carlo simulation technique. The same input data for the OOIP calculation was used in addition to recovery factors stated as percentages of OOIP. Based on reported recovery factors for units with similar reservoir characteristics and operating plan, 4 percent of OOIP was chosen as the most probable minimum infill recovery, 6 percent the most likely, and 8 percent the most probable maximum (triangular distribution). Figure 3-VIII shows the full range of total possible infill recovery volumes with their associated probabilities. The mean infill recoverable oil was calculated to be 7.1 million STB, with a standard deviation of 1.4 million STB. Based on fifty three

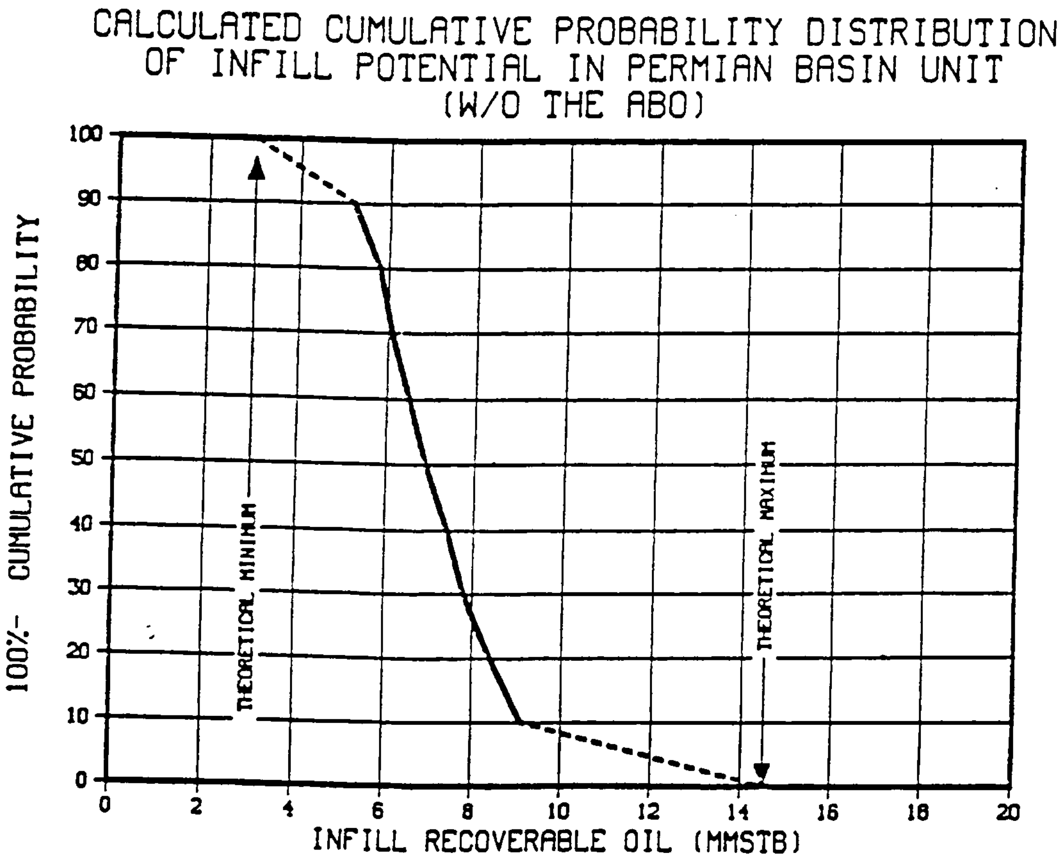


Figure 3-VIII

potential 20 acre locations in the unit area, the expected recovery per infill well was calculated to be 134,000 STB.

The analogy method was based on decline curve analysis of 20 acre infill wells in an offset Unit. Though, many units in the Clearfork trend have been infilled on 20 acres, the offset Unit was considered a suitable analog for PBU due to similarities in average rock properties and geologic characteristics. Using an analog derived exponential decline function, a total recovery of 140,000 STB per well was calculated, assuming a limiting rate of 4 BOPD. This recoverable volume of 140 MBO per well is assumed to be unique based on the offset Unit experience. The experience of this Unit showed that the 20-acre infills constituted little or no interference effects in the performance of the original 40 acre wells.

Operating Plan

Clearfork reservoirs, as stated previously, are characterized by gross nonuniformities. Often numerous, thin pay intervals of varying quality are distributed over thick vertical sections of several hundred feet. Differing environmental conditions at the time of deposition insure that the rock encountered in a particular wellbore will have markedly varying porosity, permeability, and fluid-flow characteristics and relationships. These same variations occur between wellbores. To effectively waterflood such a reservoir, it is believed that uniform areal distribution of injection is required to optimize injection into the numerous but discontinuous, low permeability zones.

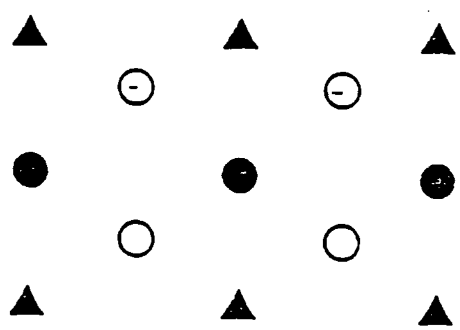
The PBU waterflood is currently operated on inverted nine-spot pattern. The main purpose of the inverted nine-spot pattern was to evaluate suspected east-west directional permeability that has been observed in some West Texas waterflood projects. Those projects experienced early water breakthroughs in producers aligned east-west to injectors. Similar premature water breakthroughs have been observed in PBU, however, these observations do not establish conclusively the presence of an east-west directional permeability, or that of induced/ natural fractures. In any case, there is significant need for pattern modification, as per the results of flood performance review. The choice of an alternate pattern was based primarily on analogy. A review of the waterflood operating pattern along the Clearfork trend was conducted. Results of the review indicated that:

1. Infilled line drive pattern (Figure 3-IX) has been successful in a Shell-operated Clearfork Unit, and a Mobil-operated Unit; and

2. The 5-spot pattern has also been successful in Amoco-operated Clearfork Units.

Each of the two patterns has resulted in significant recovery improvements in the mentioned units and it is believed that their proven effectiveness is due to the effective distribution of injection sites. However, there are two important operating differences between the two patterns. First, the infilled line drive can be implemented with a

INFILLED LINE DRIVE PATTERN



LEGEND

- 40 ACRE PRODUCER
- 40 ACRE INJECTOR
- 20 ACRE INFILL PRODUCER

2VW001316

Figure 3-IX

comparatively smaller decrease in current unit production. This difference is a major issue in practical field management. Maintaining high rates of production is a high priority in every oil company, especially in the current depressed industry environment. Second, the infilled line drive provides the flexibility for modification to a 5-spot if future operating circumstances should require it. Based on these considerations, the intern recommended an infilled line drive pattern for PBU ultimate development (Figure 3-X). This plan of development would require the future drilling of about fifty 20 acre infills, and conversion of about twenty existing 40-acre producers to injectors.

Conclusions

The objectives of the field study were met, and the following are the major conclusions:

1. The mean original oil in place in the Clearfork/Wichita Albany reservoirs of the PBU area is 118 million STB;

2. The existing waterflood operation is ineffective. Improvements can be effected through injection redistribution, addition of injectors, and opening of more pay in existing producers and injectors;

3. There is significant potential for additional recovery through 20 acre infill drilling. The expected infill recovery potential in WNCU is 7.1 million STB; and

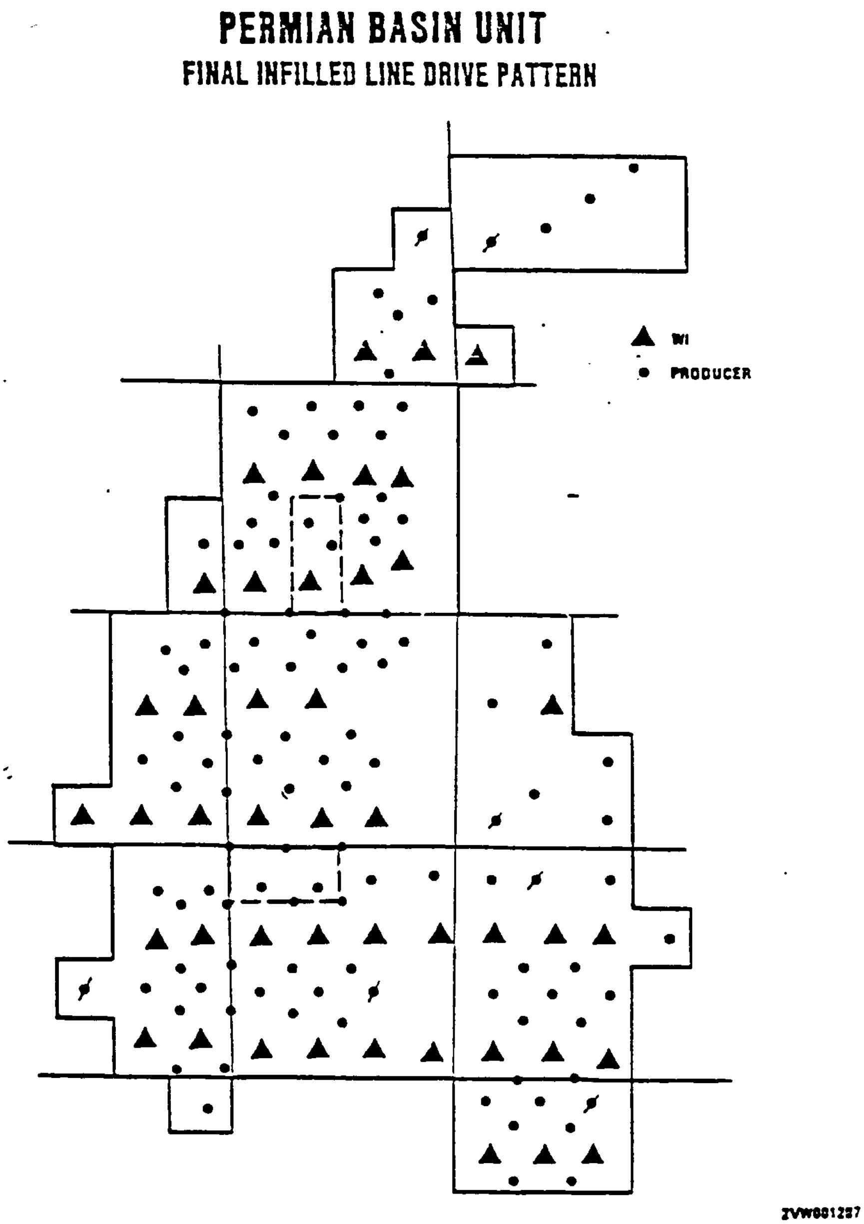

PERMIAN BASIN UNIT
FINAL INFILLED LINE DRIVE PATTERN
WI
PRODUCER
ZVW001287

Figure 3-X

4. An infilled line drive pattern is recommended for PBU ultimate development. This pattern has been successful in other Clearfork waterfloods.

3.3 JUSTIFICATION FOR INFILL DRILLING AND PRUDUCER-TO-INJECTOR CONVERSIONS

One of the author's major responsibilities during the internship was the technical planning and economic evaluation of development projects in PBU. A summary of the author's contributions during the planning phase of a project that involved capital commitments of over two million dollars will be presented in this section. The project consisted of 3 infill producers, 1 water injector, and 7 producer-to-injector (P/I) conversions.

The project justification process involved three essential steps:

- Project Definition;
- Project Justification; and
- Project Coordination.

Project Definition

The project definition process was fed partly by the conclusions reached in the waterflood enhancement study. The conclusions pointed to the need for injection improvement through addition of injectors. They also indicated that significant recovery improvements can be effected through 20 acre infill development. In addition, the 1986 business goals for PBU called for the drilling of 4 infill wells to develop proved undeveloped supplemental reserves and to increase operating cash inflow.

The intern and the immediate supervisor held several discussions on this matter in order to prioritize activities. Though, the field study showed a definite need for additional injectors, a decision still had to be made on the maximum number of producers that could be converted to injectors without impairing current production and operating income. Also, the field study indicated that the production performance of the infill wells could be better if the injection improvement measures were implemented first. Therefore, the business implications of postponing the infill wells had to be assessed. Management was consulted for guidance. Subsequently, it was decided that injection improvements and infill development would be pursued simultaneously. Seven producers were targeted for conversion. One of the four infill wells was postponed in favor of drilling a water injector in view of the urgency for waterflood improvement.

The well locations were picked jointly by the geological engineer and the intern. The locations were picked on the basis of pay continuity, location risk, and reservoir pressure. The 7 P/I conversions were based on the need for areal and uniform distribution of injection as well as pattern modification.

Project Justification

The justification involved technical and economic evaluations, and the solicitation of project approval from management.

The production schedule for the infill wells was derived from the performance of 20 acre infill wells completed in similar Clearfork reservoirs. The expected increase in field production due to the eight injectors (7 P/I conversions and 1 water injector) was also based on analogy. Current and future losses in production due to the conversion was estimated using the decline curves of the converted producers. Operating cost per well was supplied by field operations personnel. The total cost estimate for the project was provided by the drilling, production and facilities engineers. Shell economic evaluation program (SCOPE) was used by the intern for the profitability computations. Based on Shell's investment yardsticks, the project was found to be very attractive. The evaluation results were subsequently documented and attached to an AFE.

Three levels of management were required for project approval due to the amount of capital investment involved. Approval was solicited in the following order:

- Petroleum Engineering Manager
- Engineering Manager CO_2-Ventures
- Western Production Manager

Unanimous concurrence was received. Thus, the project justification process was completed.

Project Coordination

Subsequent to managerial approval, the following steps were taken by the intern and the supervisor to ensure project implementation:

- Sending the approved AFE to Finance Department. Finance certified the AFE, and mailed out ballots to partners soliciting their approval for Shell to fund the project.

- Sending letters to Production Administration and Land Departments advising them to obtain drilling permits and stake the well locations.

- Keeping other engineering groups and management informed on status of project.

The coordination effort was still going on at the time of this report. Partners have not been prompt in returning their AFE ballots. Coordination will extend to the period of drilling. Decisions regarding whether or not a well should be completed upon reaching the target depth will still have to be made by management. Such decisions are strictly based on engineering interpretation of well logs and production tests. The coordination effort will continue until all the wells are completed/ and or abandoned, and the seven producers converted to injectors.

3.4 ABO REEF PRIMARY DEVELOPMENT PROGRAM

This program involved the justification of a single well to resume the Abo reef primary development program in PBU. At the time of the justification, it was believed that two wells had been completed successfully in the Abo since the start of the program in early 1985 by Sun Oil Company, the former Unit operator. To continue exploitation of the discovered reef accumulation, a third well was to be justified. The process followed in the Abo well justification compares to that of the Infill and Conversion Program discussed in the preceding section, therefore, the following discussions would be limited only to the relevant technical and economic details.

Abo Geology

The "Abo" is a reef development confined to a narrow northeast southwest trend along the shelf margin of the North Basin Platform (see Figure 3-II). Abo field indicates a structural influence in both hydrocarbon trapping and reservoir development. Characteristically, Abo reefs seldom exceed a mile in width, and they approach a thickness of about 1000 feet. Aerial extent is often limited and averages 600 acres. Porosity development and oil column height are believed to be greatest around the top of reef structure. For this reason, Abo producers located high on reef structure have been found to be very prolific. The productive reef consists of clean, massive dolomite with an average porosity of 6 percent. Although porosity is low, the dolomite reef can be highly permeable due to beaching and collapse brecciation.

Reservoir Engineering

One of the most critical requirements in the justification of the proposed well was information on the reef hydrocarbon volume. This information was necessary in order to assess whether the existing Abo wells would be sufficient to drain the accumulation.

The major bottleneck in estimating reef size was limited availability of control points and production history. As mentioned earlier, only few wells had penetrated the reef. This created problems in the calculation of "pay" and other necessary reservoir parameters. Following several discussions with the geologist and petrophysicist, it was agreed that a risk simulation approach to volumetrics was the only practical option. The Monte Carlo simulation was subsequently used by the intern to predict OOIP and recoverable oil.

Input parameters for the Monte Carlo evaluation are provided in Table 3-IV. Figure 3-XI shows the full range of possible values for the OOIP and their associated probabilities. The calculated expected OOIP is 14.3 million STB. As shown in the figure, the probability associated with this reservoir size is 46 percent. Similar evaluation was completed for the recoverable oil. The mean or expected recoverable oil from the total accumulation was calculated to be 2.4 million STB. As Figure X-II indicates, the probability associated with this quantity of recoverable is 45 percent. The minimum recoverable oil based on 90 percent probability is 1.3 million STB. This minimum volume of 1.3 million STB was the cornerstone of this justification.

The estimated total production for the two existing Abo wells was calculated to be 553,000 STB. The production estimate was based on

TABLE 3-IV

MONTE CARLO ANALYSIS
INPUT PARAMETER DATA
FOR
THE ABO REEF

DISTRIBUTION PARAMETER	PROBABLE MINIMUM	MOST LIKELY	PROBABLE UPPER LIMIT	TYPE
A (Acres)	200	600	1000	Triangular
h (ft)	30	70	100	Triangular
ϕ (%)	6	7	9	Triangular
S_w (%)	13	20	40	Triangular
B_{oi}	1.1	1.25	1.3	Triangular
Rec. Fac. (%)	9.	18.	23.9	Triangular

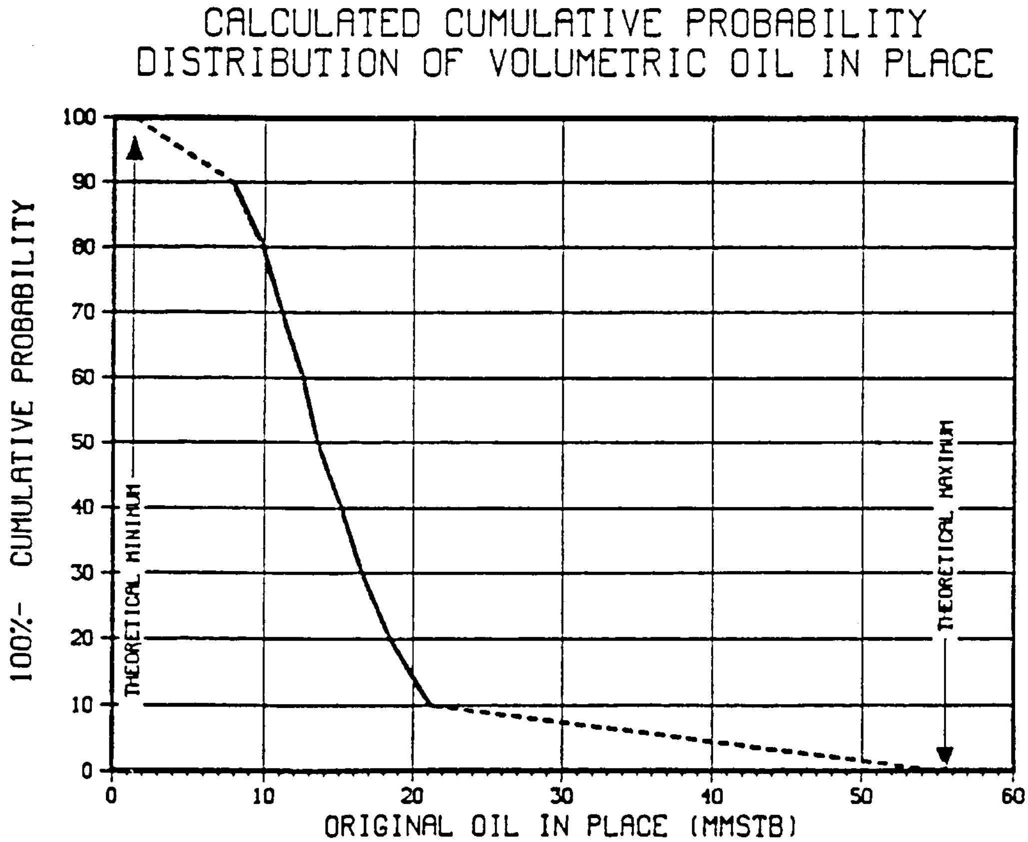

CALCULATED CUMULATIVE PROBABILITY
DISTRIBUTION OF VOLUMETRIC OIL IN PLACE
100%- CUMULATIVE PROBABILITY
ORIGINAL OIL IN PLACE (MMSTB)
THEORETICAL MINIMUM
THEORETICAL MAXIMUM
0
10
20
30
40
50
60
70
80
90
100

Figure 3-XI

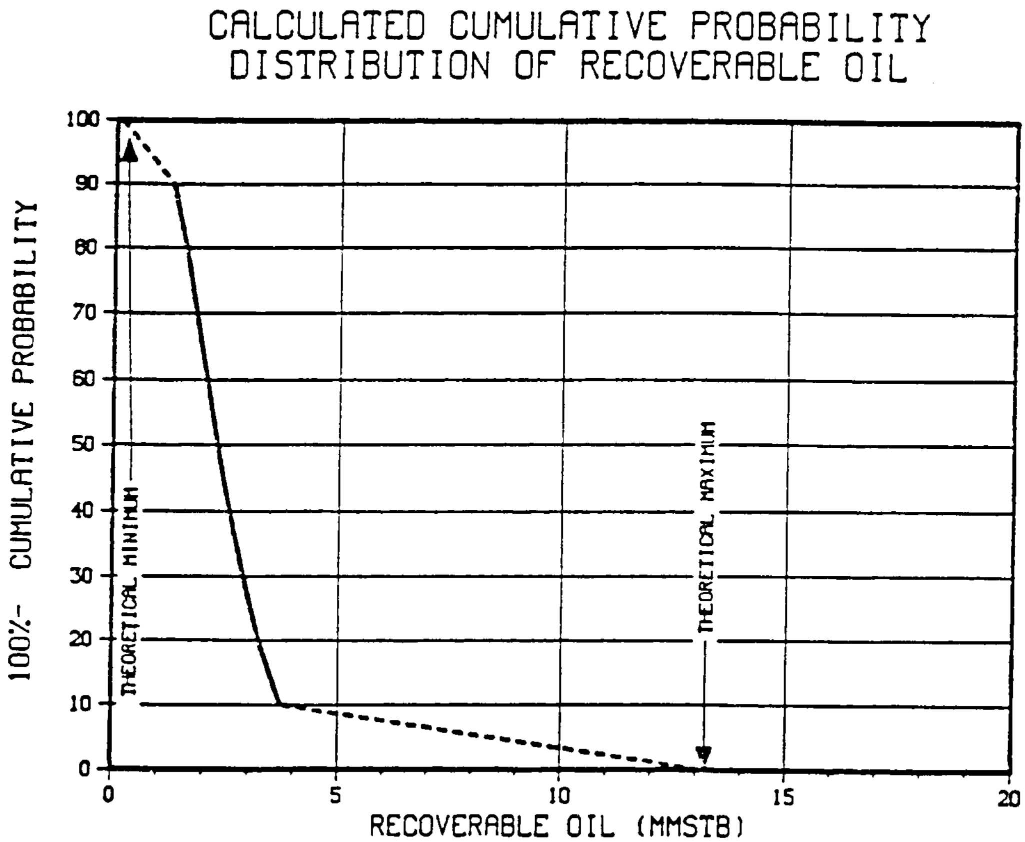

CALCULATED CUMULATIVE PROBABILITY
DISTRIBUTION OF RECOVERABLE OIL
100%- CUMULATIVE PROBABILITY
RECOVERABLE OIL (MMSTB)
THEORETICAL MINIMUM
THEORETICAL MAXIMUM
100
90
80
70
60
50
40
30
20
10
0
0
5
10
15
20

Figure 3-XII

exponential decline curve function derived from the performance history of analog Abo producers in offset units. Given a 90% probability (almost a certainty) that the minimum recoverable oil is 1.3 million STB, it then followed that the existing producers could only recover 553,000 STB, leaving 747,000 barrels undrained if no additional wells were drilled. Therefore, the need for the proposed well was very obvious. The remaining unknown was the economics of the drilling program.

Profitability Potential

A risk adjusted profitability analysis of the proposed well was completed by the author. The calculated risk - adjusted profit indicators showed that the proposed well was a worthwhile investment for SWEPI.

CHAPTER 4

BUSINESS ASSIGNMENTS

In the course of the internship, the author completed several business related assignments, and they include the:

- Preparation of the 1987 Development Capital Budget;
- Preparation of the 1987 Reserves Report;
- Preparation of the Standardized Measure of Future Net Cash Flows;
- A Unit Enlargement Evaluation (expansion of the Permian Basin Unit).

4.1 1987 DEVELOPMENT CAPITAL BUDGET

The word "Capital" refers to fixed assets used in production, while a "budget" is a plan detailing projected inflows and outflows during some future period[9]. In the Shell organization, the Capital budget provides a means whereby the individual operating divisions outline the plans for the development of their resources and the required capital investment. It is through the budget process that longer term corporate objectives are translated into specific investment plans.

Within the Western Division, each department was required to make budget submittals for 1987. Each group within the departments had the responsibility for screening development projects for the fields under its charge and deciding which ones should be included in the capital budget. The reservoir engineers in each group are responsible for preparing the individual development capital budgets. The author had the responsibility of preparing the 1987 Development Capital Budget for PBU.

The 1987 Capital Development Budget process for PBU started with an assessment of future overall development strategy for the unit. At the time of the budget exercise, the field enhancement study discussed earlier had not progressed to the point of providing information on development strategy. Therefore, gross assumptions had to be made based on the development experience of offset units along the Wasson trend. It was estimated that fourteen 20 acre infill wells will be drilled, and 17 producers converted to injectors during 1987 as part of the waterflood development. Additionally, there was an opportunity to pursue further exploitation of the Abo reef; it was estimated that 4 primary wells would be needed in 1987 to develop the reef.

The development budget was prepared under two categories: CONTINGENT-IN-BUDGET for the Abo wells and NOT-CONTINGENT for the 20-acre infills. The former is used to describe projects whose implementation is associated with a greater than normal degree of uncertainty. NOT-CONTINGENT projects are almost certain to be implemented. The budget process involved:

- Economic Evaluation of the Projects
    - Production forecasts were based on analogy
    - Cost estimates were provided by production, facilities and drilling engineers
    - Shell SCOPE program was used for the profitability computations

- Preparation of Field Plats
    - Showing approximate well locations on field maps
    - Summarizing the major economic or profitability yardsticks (e.g., real earning power, present worth profit, development capital per barrel of expected production, etc) of the projects on the field plats

- Writing-up the funds requests
    - Stating the total amount of development capital needed for the two projects
    - Explaining the assumptions and methods used for recovery projections
    - Summarizing the geologic characteristics and complexities of the project
    - Highlighting all technical and economic risks that could impact project viability

The final phase of the budget process involved making presentations to various levels of management within the Division to seek their concurrence. However, final budget approval authority resides in the top management of Shell Oil.

4.2 1987 RESERVES REPORT

Reserves Report is a summary of a company's oil and gas resources that are physically and economically producible at a particular time. It is useful as a basis for assessing the economic health of the reserves owner. Lending institutions and private investors use information contained in Reserves Report to assess the course of their commercial relationships with petroleum organizations. Additionally, the report is an important component of evaluations conducted to meet Securities and Exchange Commission disclosure requirements.

Reserves Report is prepared for each field in which SWEPI has a working interest. The responsibility for preparing the field Reserves Report is that of the reservoir engineer(s) working on the field. The individual field reports are later compiled into a single volume summarizing SWEPI's entire reserves at a particular date.

The author was responsible for the preparation of the January 1, 1987 Reserves Report for PBU. This unit is operated by SWEPI which has a unit working interest of 54%. The report preparation process involved the following.

Previous Reserve Update

This involved the subtraction of oil and gas production volumes for 1986 from the proved developed reserves of January 1, 1986. The balance was projected as the preliminary proved developed reserves estimate for January 1, 1987.

Current Reserves Assessment

An assessment was made to ascertain the technical accuracy of the preliminary reserves estimate for January 1987. This involved the use of established decline rates for similar offset fields in "playing out" the estimated remaining reserves. The object of this exercise was to determine if the remaining field life would be anomalous, either on the high or low side. An unusually high figure would indicate that the reserves estimate may need to be adjusted downward, and vice versa. On the other hand, a field life comparable with similar offset fields would indicate that the projected proved developed reserves are reasonably accurate. In the case of PBU, the projected estimate for proved developed reserves of January 1, 1987 was found to be reasonably accurate.

General Revision

Having arrived at an estimate for the remaining proved developed reserves, further analysis was necessary to determine if there was need for general revisions in both the proved developed and proved undeveloped sections of the Reserves Report. Conditions that could necessitate such revisions include:

- Discovery of new pay zones in fields discovered in prior years;

- Changes in working interests and/or royalty burden;

- Changes in economic premises;

- Transfers from undeveloped to developed sections of Reserve Report due to additional development (via drilling), etc.

Two revisions were necessary in both the proved developed and proved undeveloped reserves as a result of a change in SWEPI working interest and the completion of an infill well during 1986. During 1986, the working interest changed from 56 to 54% due to a phase change, and this necessitated a downward revision of previous reserves estimates which were based on 56%. (The unit agreement for PBU stipulates that the cumulative production of 2.7 million STB of oil in the unit area from January 1, 1977, shall precipitate a phase change, which would be marked by changes in working interests). The successful completion of an infill well required that the estimated reserves for the well be transferred from the proved undeveloped category to the proved developed section. These revisions were the final modifications made to arrive at the January 1, 1987 Reserves estimate for PBU. The report preparation process was completed after the estimates were reviewed and approved by management.

4.3 STANDARDIZED MEASURE OF FUTURE NET CASH FLOWS

The Standardized Measure of Future Net Cash Flows (SM is a continuing requirement for the Securities and Exchange Commission (SEC)

10K Report and the Annual Report. The purpose of SM is to ensure that reserves estimates have been appropriately determined. This responsibility has recently assumed high priority in oil and gas companies due to the impact of falling energy prices on their proved reserves base.

The SM is a constant dollar evaluation using current energy price, operating expenses and capital. The evaluation takes off from reserves information provided in the Reserves Report. SM evaluations are made at each "field" level. For each field, the proved developed reserves are "played out" using appropriate production forecast. The forecast could be the product of a simulation study, production decline curves, analogy etc. Operating expenses are assumed to be constant throughout the period of scheduled production. Similarly, the proved undeveloped reserves are "played out" to correspond to the timing of capital investments necessary to bring the undeveloped reserves to proved developed (producing) status. Incremental operating expenses are estimated and assumed constant over the life of the additional production. A cumulative undiscounted cash flow computation is made to determine the value of the reserves. If the cumulative undiscounted cash flow is negative, it implies that the oil and gas volumes considered as reserves may not be economically producible, and hence should not be reported as reserves. A positive cumulative undiscounted cash flow would indicate that the estimated reserves are reasonably accurate.

The intern followed the above procedure in completing the SM exercise for PBU. The estimated reserves for January 1, 1987 (which was discussed in previous section) were used for the exercise. Both the proved developed and undeveloped reserves were "played out" using analog production decline function. Current operating cost for the unit was assumed to be the same for the remaining field life. Operating cost data were supplied by the Operations Department. Capital investments for the conversion of proved undeveloped reserves to proved developed status were calculated on the basis of expected recovery and drilling cost per infill well. Drilling and completion cost estimates were provided by the Drilling, Production and Facilities engineers. The LOTUS-123 spreadsheet was used for the cash flow computations. The undiscounted cumulative cash flow using actual energy prices as of December 1986 verified that the estimated reserves of January 1, 1987 were economically producible, and hence should be considered to have been determined in accordance with SEC guidelines for standardization. These guidelines require that current energy prices, operating expenses, and development capital, unadjusted for inflation or expected increases, be used to determine the economic producibility of the oil and gas volumes reported as reserves. The purpose of this is to standardize reserves estimation procedure within the oil industry; this provides for an unbaised determination of the relative worth of petroleum companies.

4.3 UNIT ENLARGEMENT EVALUATION

An evaluation was conducted by the intern to investigate the technical and economic advisability of expanding the PBU to include non-unit 100% SWEPI windows and peripheral leases owned by an offset operator. The two SWEPI windows are located within the unit while the offset leases are located at the northeastern corner (Figure 4-I).

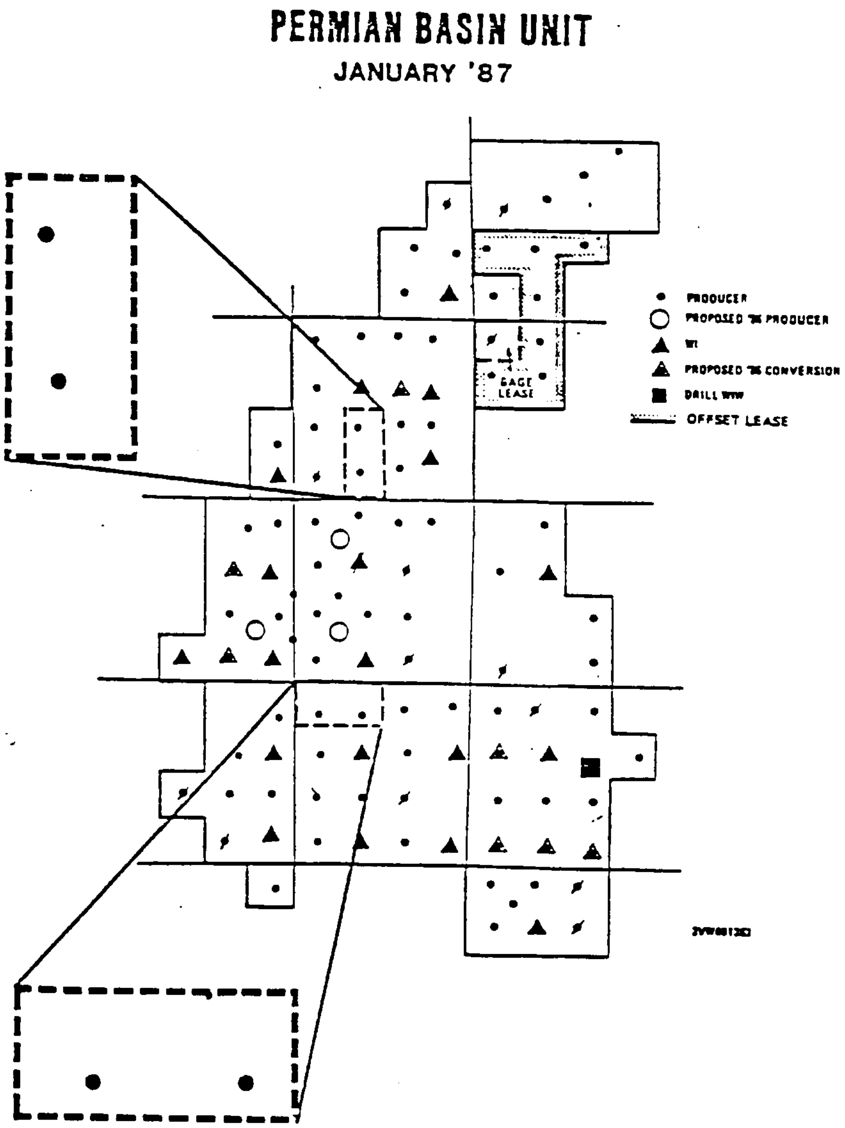

PERMIAN BASIN UNIT
JANUARY '87
PRODUCER
GAGE LEASE
OFFSET LEASE

Figure 4-I

The technical analysis was focused on this issue: "would the inclusion of these leases into PBU contribute to the improvement of the waterflood operations and the unit ultimate recovery?" As discussed in the section on waterflood enhancement study, the following plans were identified as means of improving the flood:

- addition of injectors;
- reduction of well spacing from 40 to 20 acres; and
- pattern modification towards an infilled line drive.

Figure 4-II shows that the above actions can be carried out with much more flexibility and effectiveness if the open windows and peripheral productive areas are included in the unit. The inclusion of the SWEPI leases would provide a complete infilled line drive on 20-acre spacing, allowing the opportunity for one conversion and 10 additional 20 acre producers.

The incremental economics for the proposal was found to be very attractive to all the working interest owners. The estimated capital investment for the unit enlargement was based on the intern's interpretation of the relevant provisions for unit enlargement as stated in the unit operating agreement. The unit enlargement would result in a net increase in SWEPI working interest. The incremental working interest was calculated using the tract participation formula provided in the unit agreement. Other partners will gain incremental reserves with no loss in current production. Additionally, they will receive reimbursement for past unit capital expenditures, being the penalty assessed on these leases

PERMIAN BASIN UNIT

FINAL INFILLED LINE DRIVE PATTERN

(WITH INCORPORATION OF OFFSET LEASE & SWEPI WINDOWS)

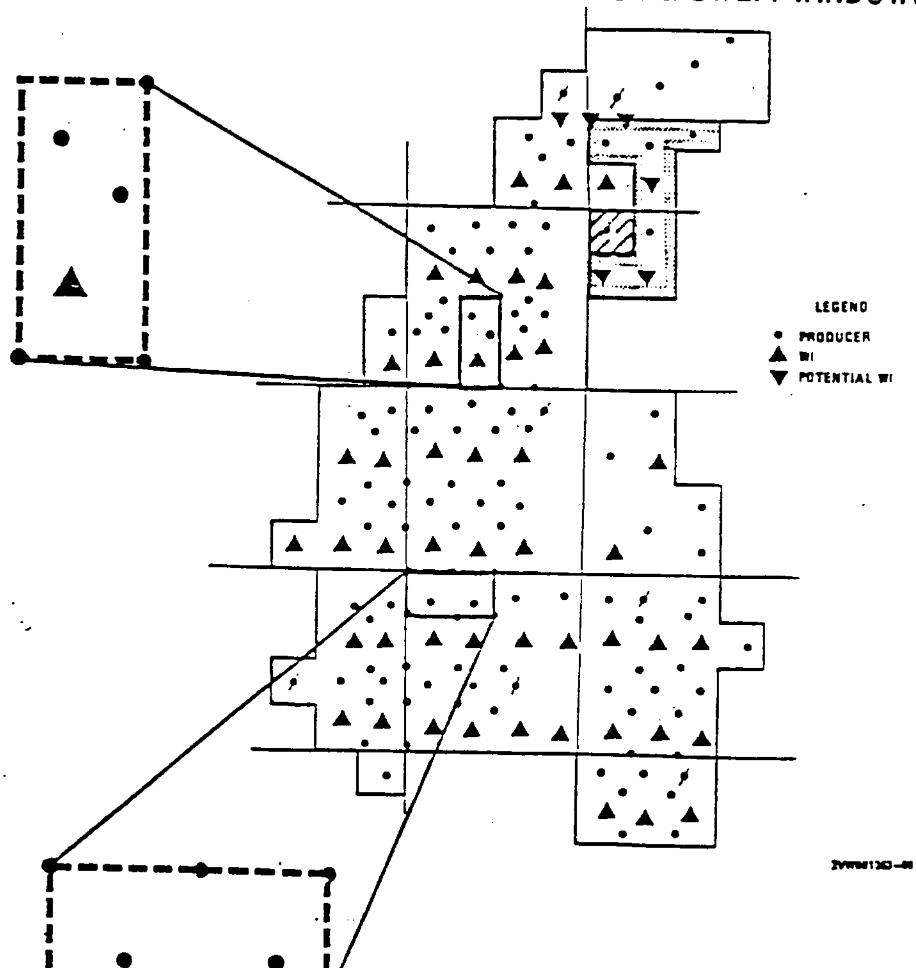


Figure 4-II

for not being part of the unit at the very start.

To pursue the proposed enlargement, the intern recommended that a Technical Committee for Unit Enlargement be created. The committee will be composed of representatives of all working interest owners. The main idea behind this strategy is to circumvent unwarranted suspicions by the partners that could sidetrack the merits of the proposal. SWEPI is the current operator of PBU, and also the owner of some of the leases to be incorporated.

The details of overall strategy to be used by SWEPI during the unit enlargement negotiations are still being worked out at the time of this report.

CHAPTER 5

SUMMARY

The author's internship which lasted twelve months (January 21, 1986 - January 21, 1987) was served in the Petroleum Engineering CO_2-Ventures Department, Shell Western E&P Inc. (SWEPI) as the Reservoir Engineer for a Permian Basin Unit. The author feels that the objectives set forth at the beginning of the internship have been fulfilled most effectively. The variety and breadth of the internship has provided a unique and invaluable framework upon which to build a successful career.

The preparation received by the author during the academic phase of the Doctor of Engineering Program has served to accelerate both the orientation process and the subsequent learning experience at SWEPI. The professional development and business course work have provided a base useful to the author while observing and being a participant in the highly complex and competitive energy business. The technical preparation has enabled the author to adapt quickly to SWEPI's engineering methodologies and to put them to use in solving the various problems addressed during the internship.

Throughout the internship, the members of the Sun Acquisition Development Group (the author's internship home) have been most helpful and encouraging. SWEPI has admirably fulfilled its portion of the internship. The author feels that the internship has indeed been profitable for both parties.

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VITA

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